FORM PTO-1390 (REV. 11-2000)	U.S. DEPARTMENT OF COMMERCE PATENT AND TRADEMARK OFFICE	ATTORNEY'S DOCKET NUMBER
SEP 1 8 200 **TRANSMITTAL LETTER TO THE UNITED STATES DESIGNATED/ELECTED OFFICE (DO/EO/US) CONCERNING A FILING UNDER 35 U.S.C. 371**		US57.0326-WO
		U.S. APPLICATION NO. (If known, see 37 CFR 1.5) **09/936863**

INTERNATIONAL APPLICATION NO.	INTERNATIONAL FILING DATE	PRIORITY DATE CLAIMED
PCT/GB00/01074	21 March 2000 (21.03.00)	22 March 1999 (22.03.99)

TITLE OF INVENTION
METHOD AND SYSTEM FOR REDUCING EFFECTS OF SEA SURFACE GHOST CONTAMINATION IN SEISMIC DATA

APPLICANT(S) FOR DO/EO/US
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Applicant herewith submits to the United States Designated/Elected Office (DO/EO/US) the following items and other information:

1. ☒ This is a **FIRST** submission of items concerning a filing under 35 U.S.C. 371.

2. ☐ This is a **SECOND** or **SUBSEQUENT** submission of items concerning a filing under 35 U.S.C. 371.

3. ☐ This is an express request to begin national examination procedures (35 U.S.C. 371(f)). The submission must include items (5), (6), (9) and (21) indicated below.

4. ☒ The US has been elected by the expiration of 19 months from the priority date (Article 31).

5. ☒ A copy of the International application as filed (35 U.S.C. 371(c)(2))

   a. ☐ is attached hereto (required only if not communicated by the International Bureau).

   b. ☒ has been communicated by the International Bureau.

   c. ☐ is not required, as the application was filed in the United States Receiving Office (RO/US).

6. ☐ An English language translation of the International Application as filed (35 U.S.C. 371(C)(2)).

   a. ☐ is attached hereto.

   b. ☐ has been previously submitted under 35 U.S.C. 154(d)(4).

7. ☐ Amendments to the claims of the International Application under PCT Article 19 (35 U.S.C. 371(c)(3)).

   a. ☐ are attached hereto (required only if not communicated by the International Bureau).

   b. ☐ have been communicated by the International Bureau.

   c. ☐ have not been made; however, the time limit for making such amendments has NOT expired.

   d. ☐ have not been made and will not be made.

8. ☐ An English language translation of the amendments to the claims under PCT Article 19 (35 U.S.C. 371 (c)(3)).

9. ☐ An oath or declaration of the inventor(s) (35 U.S.C. 371(c)(4)).

10. ☐ An English language translation of the annexes of the International Preliminary Examination Report under PCT Article 36 (35 U.S.C. 371(c)(5)).

Items 11 to 20 below concern document(s) or information included:

11. ☐ An Information Disclosure Statement under 37 CFR 1.97 and 1.98.

12. ☐ An assignment document for recording. A separate cover sheet in compliance with 37 CFR 3.28 and 3.31 is included.

13. ☐ A FIRST preliminary amendment.

14. ☐ A SECOND or SUBSEQUENT preliminary amendment.

15. ☐ A substitute specification.

16. ☐ A change of power of attorney and/or address letter.

17. ☐ A computer-readable form of the sequence listing in accordance with PCT Rule 13ter.2 and 35 U.S.C. 1.821-1.825.

18. ☒ A second copy of the published international application under 35 U.S.C. 154(d)(4).

19. ☐ A second copy of the English language translation of the international application under 35 U.S.C. 154(d)(4).

20. ☒ Other items or information:
PCT/IB/308 Form "Notice Informing the Applicant of the Communication of the Int'l Appl. to the Designated Offices"
PCT/IPEA/416 Form "Notification of Transmittal of the Int'l Preliminary Examination Report"
PCT/IPEA/409 Form "International Preliminary Examination Report

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U.S. APPLICATION NO. (if known, see 37 CFR 1.5)	INTERNATIONAL APPLICATION NO	ATTORNEY'S DOCKET NUMBER
09/936863	PCT/GB00/01074	US57.0326-WO

21. ☒ The following fees are submitted:

BASIC NATIONAL FEE (37 CFR 1.492 (a) (1) - (5)):

Neither international preliminary examination fee (37 CFR 1.482)
nor international search fee (37 CFR 1.445(a)(2) paid to USPTO
and International Search Report not prepared by the EPO or JPO **$1000.00**

International preliminary examination fee (37 CFR 1.482) not paid to
USPTO but International Search Report prepared by the EPO or JPO.......... **$860.00**

International preliminary examination fee (37 CFR 1.482) not paid to USPTO
but international search fee (37 CFR 1.445(a)(2)) paid to USPTO **$710.00**

International preliminary examination fee (37 CFR 1.482) paid to USPTO
but all claims did not satisfy provisions of PCT Article 33(1)-(4).................. **$690.00**

International preliminary examination fee (37 CFR 1.482) paid to USPTO
and all claims satisfied provisions of PCT Article 33(1)-(4)........................... **$100.00**

	CALCULATIONS PTO USE ONLY

ENTER APPROPRIATE BASIC FEE AMOUNT =	$860.00	

Surcharge of **$130.00** for furnishing the oath or declaration later than ☐ 20 ☒ 30 months from the earliest claimed priority date (37 CFR 1.492(e)).	$130.00	

CLAIMS	NUMBER FILED	NUMBER EXTRA	RATE		
Total claims	29 - 20 =	9	x $18.00	$162.00	
Independent claims	4 - 3 =	1	x $80.00	$80.00	
MULTIPLE DEPENDENT CLAIM(S) (if applicable)			+ $270.00	$	
		TOTAL OF ABOVE CALCULATIONS =		$	

☐ Applicant claims small entity status. See 37 CFR 1.27. The fees indicated above are reduced by 1/2.	$	
SUBTOTAL = +	$1232.00	
Processing fee of **$130.00** for furnishing the English translation later than ☐ 20 ☐ 30 months from the earliest claimed priority date (37 CFR 1.492(f)).	$	
TOTAL NATIONAL FEE =	$1232.00	
Fee for recording the enclosed assignment (37 CFR 1.21(h)). The assignment must be accompanied by an appropriate cover sheet (37 CFR 3.28, 3.31). **$40.00** per property +	$	
TOTAL FEES ENCLOSED =	$1232.00	

		Amount to be refunded:	$
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a. ☐ A check in the amount of $_____ to cover the above fees is enclosed.

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NOTE: Where an appropriate time limit under 37 CFR 1.494 or 1.495 has not been met, a petition to revive (37 CFR 1.137 (a) or (b)) must be filed and granted to restore the application to pending status.

SEND ALL CORRESPONDENCE TO:

Intellectual Property Law Department
Schlumberger-Doll Research
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September 17, 2001

SIGNATURE

William B. Batzer
NAME

37,088
REGISTRATION NUMBER

Method and System For Reducing Effects of Sea Surface Ghost
Contamination In Seismic Data

FIELD OF THE INVENTION:

5   The present invention relates to the field of
reducing the effects of sea-surface ghost reflections in
seismic data. In particular, the invention relates an
improved de-ghosting method that utilises measurements or
estimates of multi-component marine seismic data recorded in
10 a fluid medium.

BACKGROUND OF THE INVENTION:

    Removing the ghost reflections from seismic data
is for many experimental configurations equivalent to
15 up/down wavefield separation of the recorded data. In such
configurations the down-going part of the wavefield
represents the ghost and the up-going wavefield represents
the desired signal. Exact filters for up/down separation of
multi-component wavefield measurements in Ocean Bottom Cable
20 (OBC) configurations have been derived by Amundsen and
Ikelle, and are described in U.K. Patent Application Number
9800741.2. An example of such a filter corresponding to de-
ghosting of pressure data at a frequency of 50 Hz for a
seafloor with P-velocity of 2000 m/s, S-velocity of 500 m/s
25 and density of 1800 kg/m3 is shown in Figure 2. At this
frequency, the maximum horizontal wavenumber for P-waves
right below the seafloor is $k=0.157$ m^{-1}, whereas it is
$k=0.628$ m^{-1} for S-waves. Notice the pole and the kink due to
a zero in the filter at these two wavenumbers, making
30 approximations necessary for robust filter implementations.
Figure 3 shows approximations to the filter. These filters

are only good at wavenumbers smaller than the wavenumber
where the pole occurs. Hence, energy with low apparent
velocities (for instance S-waves or Scholte waves at the
seafloor) will not be treated properly. Moreover, since
5   they do not have a complex part, evanescent waves will also
not be treated properly.

          The OBC de-ghosting filters have been shown to
work very well on synthetic data. However, apart from the
difficulty with poles and zeros at critical wave numbers,
10   they also require knowledge about the properties of the
immediate sub-bottom locations as well as
hydrophone/geophone calibration and coupling compensation.

          A normal incidence approximation to the de-
ghosting filters for data acquired at the sea floor was
15   described by Barr, F.J. in U.S. Patent: 4,979,150, issued
1990, entitled 'System for attenuating water-column
reflections', (hereinafter "Barr (1990)"). For all
practical purposes, this was previously described by White,
J.E., in a 1965 article entitled 'Seismic waves: radiation,
20   transmission and attenuation', McGraw-Hill (hereinafter
"White (1965)"). However, this technique is not effective
when the angle of incidence is away from vertical. Also,
this technique does not completely correct for wide-angle
scattering and the complex reflections from rough sea
25   surfaces. Additionally, its is believed that the OBC
techniques described have not been used successfully in a
fluid medium, such as with data gathered with towed
streamers.

SUMMARY OF THE INVENTION:

Thus, it is an object of the present invention to provide a method of de-ghosting which improves attenuation of noise from substantially all non-horizontal angles of incidence.

It is an object of the present invention to provide a method of de-ghosting of seismic measurements made in a fluid medium which improves attenuation of the ghost as well as downward propagating noise from substantially all non-horizontal angles of incidence.

Also, it is an object of the present invention to provide a method of de-ghosting which is not critically dependent on knowledge about the properties of the surrounding fluid medium as well as hydrophone/geophone calibration and coupling compensation.

Also, it is an object of the present invention to provide a method of de-ghosting whose exact implementation is robust and can be implemented efficiently.

According to the invention, a method is described for sea surface ghost correction through the application of spatial filters to the case of marine seismic data acquired in a fluid medium. Using, for example, either typical towed streamer or vertical cable geometries. Preferably, both pressure and vertical velocity measurements are acquired along the streamer. The invention takes advantage of non-conventional velocity measurements taken along a marine towed streamer, for example. New streamer designs are currently under development and are expected to become commercially available in the near future. For example, the Defence Evaluation and Research Agency (DERA), based in

Dorset, U.K., claim to have successfully built such a
streamer for high frequency sonar applications.

According to an alternative embodiment, the
invention is also applicable to seismic data obtained with
5   configurations of multiple conventional streamers. Here,
the filters make use of vertical pressure gradient
measurements, as opposed to velocity measurements.
According to the invention, an estimate of the vertical
pressure gradient can be obtained from over/under twin
10 streamer data, or more generally from streamer data acquired
by a plurality of streamers where the streamers are
spatially deployed in a manner analogous to that described
in U.K Patent Application Number 9820049.6, by Robertsson,
entitled 'Seismic detection apparatus and related method"
15 filed in 1998 (hereinafter "Robertsson (1998)"). For
example, three streamers can be used, forming a triangular
shape cross-section along their length. Vertical pressure
gradient data can also be obtained from pressure gradient
measuring devices.

20 According to the invention, the filters fully
account for the rough sea perturbed ghost, showing
improvement over other techniques based on normal incidence
approximations (see e.g., White (1965)), which have been
applied to data recorded at the sea floor.

25 Advantageously, according to preferred embodiments
of the invention, the results are not sensitive to streamer
depth, allowing the streamer(s) to be towed at depths below
swell noise contamination, hence opening up the acquisition
weather window where shallow towed streamer data would be
30 unusable. Local streamer accelerations will be minimised in
the deep water flow regime, improving resolution of the

pressure, multi-component velocity and pressure gradient
measurements.

Advantageously, according to preferred embodiments
of the invention, there are no filter poles in the data
5   window, except for seismic energy propagating horizontally
at the compressional wave speed in water.

Advantageously, according to preferred embodiments
of the invention, the filter is not critically dependent on
detailed knowledge of the physical properties of the
10   surrounding fluid medium.

The filters can be simple spatial convolutions,
and with the regular geometry of typical towed streamer
acquisition the filters are efficient to apply in the
frequency-wavenumber (FK) domain. The filters can also be
15   formulated for application in other domains, such as time-
space and intercept time-slowness (τ-p).

According to the invention, a method of reducing
the effects in seismic data of downward propagating
reflected and scattered acoustic energy travelling in a
20   fluid medium is provided. The method advantageously makes
use of two types of data: pressure data, that represents the
pressure in the fluid medium, such as sea water, at a number
of locations; and vertical particle motion data, that
represents the vertical particle motion of the acoustic
25   energy propagating in the fluid medium at a number of
locations within the same spatial area as the pressure data.
The distance between the locations that are represented by
the pressure data and the vertical particle motion data in
each case is preferably less than the Nyquist spatial
30   sampling criterion. The vertical particle motion data can

be in various forms, for example, velocity, pressure
gradient, displacement, or acceleration.

The spatial filter is created by calculating a
number of coefficients that are based on the velocity of
5   sound in the fluid medium and the density of the fluid
medium. The spatial filter is designed so as to be
effective at separating up and down propagating acoustic
energy over substantially the entire range of non-horizontal
incidence angles in the fluid medium.

10 The spatial filter is applied to either the
vertical particle motion data or to the pressure data, and
then combined with the other data to generate pressure data
that has its up and down propagating components separated.
The separated data are then processed further and analysed.
15 Ordinarily the down-going data would be analysed, but the up
going data could be used instead if the sea surface was
sufficiently calm.

According to an alternative embodiment, a method
of reducing the effects of downward propagating reflected
20 and scattered acoustic energy travelling in a fluid medium
is provided wherein the pressure data and vertical particle
motion data represent variations caused by a first source
event and a second source event. The source events are
preferably generated by firing a seismic source at different
25 locations at different times, and the distance between the
locations is preferably less than the Nyquist spatial
sampling criterion.

The present invention is also embodied in a
computer-readable medium which can be used for directing an
30 apparatus, preferably a computer, to reduce the effects in
seismic data of downward propagating reflected and scattered

acoustic energy travelling in a fluid medium as otherwise
described herein.

BRIEF DESCRIPTION OF THE DRAWINGS:

5   Figure 1 shows examples of simple seismic ray
paths for primary events, and ghosts that are last reflected
from the rough sea-surface;
           Figure 2 shows an exact pressure de-ghosting
filter for OBC data for a seafloor with P-velocity of 2000
10   m/s, S-velocity of 500 m/s and density of 1800 kg/m3; the
upper panel shows the Real part of exact filter; and the
lower panel shows the Imaginary part of exact filter;
           Figure 3 shows the Real part of the exact OBC de-
ghosting filter (in the solid line) shown in Figure 2, the
15   first order Taylor approximation filter (in the plus line),
and the first four fractional expansion approximations
filters (in the dash-dotted lines);
           Figure 4 illustrates the potential impact of 3D
rough sea surface ghost reflection and scattering on
20   consistency of the seismic data waveform;
           Figure 5 illustrates the potential impact of the
rough sea surface ghost perturbation on time-lapse seismic
data quality;
           Figures 6a-6f show various embodiments for data
25   acquisition set-ups and streamer configurations according to
preferred embodiments of the invention;
           Figure 7 shows an exemplary two-dimensional
spatial filter response (ω/k_z) for dx=6m;
           Figure 8 is a flow chart illustrating some of the
30   steps of the de-ghosting method for the combination of

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pressure and vertical velocity data to achieve separated
pressure data, according to a preferred embodiment of the
invention;

5   Figure 9 schematically illustrates an example of a
data processor that can be used to carry out preferred
embodiments of the invention;

Figure 10 shows an example of a shot record
computed below a 4m significant wave height (SWH) rough sea
surface, the left panel shows pressure, and the right panel
10   shows vertical velocity scaled by water density and the
compressional wave speed in water;

Figure 11 illustrates de-ghosting results of the
shot record in Figure 10, the left panel shows results using
the vertical incidence approximation, and the right panel
15   illustrates the exact solution;

Figure 12 illustrates an example of de-ghosting
results in detail for a single trace at 330m offset
corresponding to an arrival angle of about 37 degrees, the
upper panel shows the vertical incidence approximation, and
20   the lower panel shows the Exact solution; and

Figures 13a-b illustrate two possible examples of
multi-component streamer design.

25   DETAILED DESCRIPTION OF THE INVENTION:

Figure 1 is a schematic diagram showing
reflections between a sea surface (S), sea floor (W) and a
target reflector (T). Various events that will be recorded
in the seismogram are shown and are labelled according to
30   the series of interfaces they are reflected at. The stars

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indicate the seismic source and the arrowheads indicate the
direction of propagation at the receiver. Events ending
with 'S' were last reflected at the rough sea surface and
are called receiver ghost events. Down-going sea-surface
5   ghost reflections are an undesirable source of
contamination, obscuring the interpretation of the desired
up-going reflections from the earth's sub-surface.

        Rough seas are a source of noise in seismic data.
Aside from the often-observed swell noise, further errors
10   are introduced into the reflection events by ghost
reflection and scattering from the rough sea surface. The
rough sea perturbed ghost events introduce errors that are
significant for time-lapse seismic surveying and the
reliable acquisition of repeatable data for stratigraphic
15   inversion.

        The effect of the rough sea is to perturb the
amplitude and arrival time of the sea surface reflection
ghost and add a scattering coda, or tail, to the ghost
impulse. The impulse response can be calculated by finite
20   difference or Kirchhoff methods (for example) from a
scattering surface which represents statistically typical
rough sea surfaces. For example, a directional form of the
Pierson-Moskowitz spectrum described by Pierson, W.J. and
Moskowitz, L., 1964 'A proposed Spectral Form for Fully
25   Developed Wind Seas Based on the Similarity Theory of S. A.
Kitaigorodskii' J. Geo. Res., 69, 24, 5181-5190,
(hereinafter "Pierson and Moskowitz (1964)"), and
Hasselmann, D. E., Dunckel, M. and Ewing, J.A., 1980
'Directional Wave Spectra Observed During JONSWAP 1973', J.
30   Phys. Oceanography, v10, 1264-1280, (hereinafter "Hasselmann
et al, (1980)"). Both the wind's speed and direction define

the spectra. The Significant Wave Height ("SWH") is the
subjective peak to trough wave amplitude, and is about equal
to 4 times the RMS wave height. Different realisations are
obtained by multiplying the 2D surface spectrum by Gaussian
5   random complex numbers.

Figure 4 shows an example of rough sea impulses
along a 400m 2D line (e.g. streamer) computed under a 2m SWH
3D rough sea surface. The streamer shape affects the details
of the impulses, and in this example the streamer is
10   straight and horizontal. Figure 4 shows, from top to bottom:
The ghost wavelet (white trough) arrival time, the ghost
wavelet maximum amplitude, a section through the rough sea
realisation above the streamer, and the computed rough sea
impulses. The black peak is the upward travelling wave,
15   which is unperturbed; the white trough is the sea ghost
reflected from the rough sea surface. The latter part of the
wavelet at each receiver is the scattering coda from
increasingly more distant parts of the surface. Notice that
the amplitude and arrival time ghost perturbations change
20   fairly slowly with offset. The arrival time perturbations
are governed by the dominant wavelengths in the sea surface,
which are 100-200m for 2-4m SWH seas, and the amplitude
perturbations are governed by the curvature of the sea
surface which has an RMS radius of about 80m and is fairly
25   independent of sea state. The diffraction coda appear as
quasi-random noise following the ghost pulse.

The rough sea perturbations cause a partial fill
and a shift of the ghost notch in the frequency domain. They
also add a small ripple to the spectrum, which amounts to 1-
30   2dB of error for typical sea states. In the post stack

domain this translates to an error in the signal that is
about -20dB for a 2m SWH sea.

Figure 5 shows an example of how such an error can
be significant for time-lapse surveys. The panel on the top
5   left shows a post-stack time-migrated synthetic finite
difference seismic section. The top middle panel shows the
same data but after simulating production in the oil
reservoir by shifting the oil water contact by 6m and
introducing a 6m partial depletion zone above this. The
10   small difference is just noticeable on the black leg of the
reflection to the right of the fault just below 2s two-way
travel-time. The panel on the right (top) shows the
difference between these two sections multiplied by a factor
of 10. This is the ideal seismic response from the time-
15   lapse anomaly.

The left and middle bottom panels show the same
seismic sections, but rough sea perturbations for a 2m SWH
(as described above) have been added to the raw data before
processing. Note that different rough sea effects are added
20   to each model to represent the different seas at the time of
acquisition. The difference obtained between the two
sections is shown on the bottom right panel (again
multiplied by a factor of 10). The errors in the reflector
amplitude and phase (caused by the rough sea perturbations)
25   introduce noise of similar amplitude to the true seismic
time-lapse response. To a great extent, the true response is
masked by these rough sea perturbations. A method for
correcting these types of error is clearly important in such
a case, and with the increasing requirement for higher
30   quality, low noise-floor data, correction for the rough sea
ghost becomes necessary even in modest sea states.

Equation (1) gives the frequency domain expression for a preferred filter relating the up-going pressure field, $p^u(x)$, to the total pressure, $p(x)$, and vertical particle velocity, $v_z(x)$.

$$p^u(x) = 0.5\left[p(x) + \frac{\rho\omega}{k_z} * v_z(x)\right] \qquad (1)$$

where k_z is the vertical wavenumber for compressional waves in the water, ρ is the density of water and * denotes spatial convolution.

The vertical wavenumber is calculated from $k_z^2 = k^2 - k_x^2$ for two-dimensional survey geometries, or $k_z^2 = k^2 - k_x^2 - k_y^2$ for three-dimensional survey geometries, with $k^2 = \omega^2/c^2$, where c is the compressional wave speed in the water and k_x is the horizontal wavenumber for compressional waves in the water. The regular sampling of typical towed streamer data allows k_z to be calculated efficiently in the FK domain. Figure 7 shows an example of the filter response, ω/k_z for dx=6m (the filter is normalised for the display to an arbitrary value). Infinite gain poles occur when k_z is zero. This corresponds to energy propagating horizontally (at the compressional wave speed in water). For towed streamer data, there is little signal energy with this apparent velocity, any noise present in the data with this apparent velocity should be filtered out prior to the filter application, or, the filter should be tapered at the poles prior to application to avoid amplification of the noise.

The traditional filter (White (1965), Barr, (1990)) is equation (2):

$$p^u = 0.5[p + \rho c\, v_z]$$ (2)

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By comparison to equation (1), we see that this is a normal incidence approximation, which occurs when k_x is zero. This is implemented as a simple scaling of the vertical velocity trace followed by its addition to the

10   pressure trace.

Equation (1) can also be formulated in terms of the vertical pressure gradient (dp(x)/dz). The vertical pressure gradient is proportional to the vertical acceleration:

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$$dp(x)/dz = \rho\, dv_z(x)/dt$$ (3)

Integrating in the frequency domain through division of $i\omega$, and substituting in equation (1) gives:

20

$$p^u(x) = 0.5\left[p(x) + \frac{1}{ik_z} * dp(x)/dz \right]$$ (4)

Figures 6a-6f show various embodiments for data

25   acquisition set-ups and streamer configurations according to preferred embodiments of the invention. Figure 6a shows a seismic vessel 120 towing a seismic source 110 and a seismic streamer 118. The sea surface is shown by reference number 112. In this example, the depth of streamer 118 is about 60

30   meters, however those of skill in the art will recognise

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that a much shallower depth would ordinarily be used such as
6-10 meters. The dashed arrows 122a-d show paths of seismic
energy from source 110. Arrow 122a shows the initial down-
going seismic energy. Arrow 122b shows a portion of the
5   seismic energy that is transmitted through the sea floor
114. Arrow 122c shows an up-going reflection. Arrow 122d
shows a down-going ghost reflected from the surface.
According to the invention, the down-going rough sea
receiver ghost 122d can be removed from the seismic data.
10   Figures 6b-6f show greater detail of acquisition
set-ups and streamer configurations, according to the
invention. Figure 6b shows a multi-component streamer 124.
The streamer 124 comprises multiple hydrophones (measuring
pressure) 126a, 126b, and 126c, and multiple 3C geophones
15   (measuring particle velocity in three directions x, y, and
z) 128a, 128b, and 128c. The spacing between the hydrophones
126a and 126b, and between geophones 128a and 128b is shown
to be less than 12 meters. Additionally, the preferred
spacing in relation to the frequencies of interest is
20   discussed in greater detail below.
            Figure 6c shows a streamer 130 that comprises
multiple hyrdophones 132a, 132b, and 132c, and multiple
pressure gradient measuring devices 134a, 134b, and 134c.
The spacing between the hydrophones 132a and 132b, and
25   between pressure gradient measuring devices 134a and 134b is
shown to be less than 12 meters.
            Figure 6d shows a multi-streamer configuration
that comprises hydrophone streamers 140a and 140b. The
streamers comprise multiple hyrdophones 142a, 142b, and 142c
30   in the case of streamer 140a, and 142d, 142e, and 142f in
the case of streamer 140b. The spacing between the

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hydrophones is shown to be less than 12 meters. The
separation between steamers 140a and 140b in the example
shown in Figure 6d is less then 2 meters. Although the
preferred separation is less than 2 meters, greater
5   separations are contemplated as being within the scope of
the invention. Figure 6e shows a cross sectional view of a
dual streamer arrangement. Figure 6f shows a multi-streamer
configuration comprising three hydrophone streamers 140a,
140b, and 140c.

10   Adequate spatial sampling of the wavefield is
highly preferred for the successful application of the de-
ghosting filters. For typical towed streamer marine data, a
spatial sampling interval of 12m is adequate for all
incidence angles. However, to accurately spatially sample
15   all frequencies up to 125Hz (for all incidence angles), a
spatial sampling interval of 6.25 meters is preferred.
These spacings are determined according to the Nyquist
spatial sampling criterion. Note that if all incidence
angles are not required, a coarser spacing than described
20   above can be used. The filters can be applied equally to
both group formed or point receiver data.

           Figure 8 is a flow chart illustrating some of the
steps of the de-ghosting method for the combination of
pressure and vertical velocity data to achieve separated
25   pressure data, according to a preferred embodiment of the
invention. In step 202, spatial filter coefficients are
calculated. The coefficients are preferably dependent on
the characteristics of the acquisition parameters 203 (such
as the temporal sample interval of the pressure and particle
30   motion data, the spatial separation of the vertical particle
motion measuring devices, and the spatial aperture of the

15

filter), the density of the fluid medium 206, and the speed
of the compressional wave in the fluid medium (or velocity
of sound) 204. Vertical particle motion data 208 and
pressure data 212 are received, typically stored as time
5   domain traces on a magnetic tape or disk. In step 210, the
vertical particle motion data 208 are convolved in with the
spatial filter to yield filtered vertical particle motion
data. In step 214 the filtered vertical particle motion
data are added to pressure data 212 to give the downward
10 propagating component of the separated pressure data.
Alternatively, in step 216 the filtered vertical particle
motion data are subtracted from pressure data 212 to give
the upward propagating component of the separated pressure
data. Finally, in step 218 the upward component is further
15 processes and analysed.

        The processing described herein is preferably
performed on a data processor configured to process large
amounts of data. For example, Figure 9 illustrates one
possible configuration for such a data processor. The data
20 processor typically consists of one or more central
processing units 350, main memory 352, communications or I/O
modules 354, graphics devices 356, a floating point
accelerator 358, and mass storage devices such as tapes and
discs 360. It will be understood by those skilled in the
25 art that tapes and discs 360 are computer-readable media
that can contain programs used to direct the data processor
to carry out the processing described herein.

        Figure 10 shows a shot record example, computed
under a 4m Significant Wave Height (SWH) sea and using the
30 finite-difference method described by Robertsson, J.O.A.,
Blanch, J.O. and Symes, W.W., 1994 'Viscoelastic finite-

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difference modelling' Geophysics, 59, 1444-1456 (hereinafter
"Robertsson et al. (1994)") and Robertsson, J.O.A., 1996 'A
Numerical Free-Surface Condition for Elastic/Viscoelastic
Finite-difference modelling in the Presence of Topography',
5   Geophysics, 61, 6, 1921-1934 (hereinafter "Robertsson
(1996)"). The streamer depth in this example is 60m. The
left panel shows the pressure response and the right panel
shows the vertical velocity response scaled by the water
density and the compressional wave speed in water. A point
10   source 50Hz Ricker wavelet was used and the streamer depth
was 60m in this example. The choice of streamer depth allows
a clear separation of the downward travelling ghost from the
upward travelling reflection energy for visual clarity of
the de-ghosting results. The trace spacing on the plot is
15   24m. A single reflection and its associated ghost are shown,
along with the direct wave travelling in the water layer.
Perturbations in the ghost wavelet and scattering noise from
the rough sea surface are evident.

         Figure 11 shows the results of de-ghosting the
20   shot record shown in Figure 10. The left panel shows the
result using the normal incidence approximation and the
right panel shows the result using the exact solution. The
exact solution shows a consistent response over all offsets,
whereas the normal incidence approximation starts to break
25   down at incident angles greater than about 20 degrees, and
shows a poorer result at the near offsets. Note that the
direct wave is not amplified by the exact filter application
even though the poles of the filter lie close to its
apparent velocity. The exact filter is tapered before
30   application such that it is has near unity response for
frequencies and wavenumbers corresponding to apparent

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velocities of 1500m/s and greater. The weak event just below
the signal reflection is a reflection from the side
absorbing boundary of the model. It is upward travelling and
hence untouched by the filter.

5   Figure 12 shows details of the de-ghosted results
for a single trace from Figure 11. The trace offset is 330m
corresponding to a 37 degree incidence angle. The upper
panel shows the normal incidence approximation, and the
lower panel shows the exact solution. Not only does the
10 exact solution provide a superior result in terms of the de-
ghosting, but also in terms of amplitude preservation of the
signal reflection - the upper panel shows loss of signal
amplitude after the de-ghosting.

          The filters described herein are applicable to,
15 for example, measurements of both pressure and vertical
velocity along the streamer. Currently, however, only
pressure measurements are commercially available.
Therefore, engineering of streamer sections that are capable
of commercially measuring vertical velocity is preferred in
20 order to implement the filters.

          Figures 13a-b illustrate two possible examples of
multi-component streamer design. Figure 13a shows a
coincident pressure and single 3-component geophone. In
this design, the 3-component geophone is perfectly decoupled
25 from the streamer. Figure 13b shows a coincident pressure
and twin 3-component geophones. In this design, one of the
3-component geophones is decoupled from the streamer, the
other is coupled to the streamer; measurements from both are
combined to remove streamer motion from the data.

30   In an alternative formulation, the filters make
use of vertical pressure gradient measurements. An estimate

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of vertical pressure gradient can be obtained from
over/under twin streamers (such as shown in Figures 6d and
6e) and multiple streamers (such as shown in Figure 6f)
deployed in configurations analogous to that described in
5   Robertsson (1998), allowing the filters to be directly
applied to such data. However, for the results to remain
sufficiently accurate, the streamers should not be
vertically separated by more than 2m for seismic frequencies
below approximately 80Hz.

10   An important advantage of multiple streamer
configurations such as shown in Figure 6f is that their
relative locations are less crucial than for over/under twin
streamer geometries, where the two streamers are preferably
directly above one another.

15   The filters described here are applied in 2D
(along the streamer) to data modelled in 2D. The application
to towed streamer configurations naturally lends itself to
this implementation, the cross-line (streamer) sampling of
the wavefield being usually insufficient for a full 3D
20   implementation. Application of these filters to real data
(with ghost reflections from 3D sea surfaces) will give rise
to residual errors caused by scattering of the wavefield
from the cross-line direction. This error increases with
frequency though is less than 0.5dB in amplitude and 3.6° in
25   phase for frequencies up to 150Hz, for a 4m SWH sea. These
small residual noise levels are acceptable when time-lapse
seismic surveys are to be conducted.

             Invoking the principle of reciprocity, the filters
can be applied in the common receiver domain to remove the
30   downward travelling source ghost. Reciprocity simply means

that the locations of source and receiver pairs can be
interchanged, (the ray path remaining the same) without
altering the seismic response. Figure 1 can also be used to
define the source ghost if the stars are now regarded as
5   receivers and the direction of the arrows is reversed, with
the source now being located at the arrow. This application
is particularly relevant for data acquired using vertical
cables, which may be tethered, for example, to the sea
floor, or suspended from buoys. In the case of Figure 6a,
10 those of skill in the art will understand that as the
seismic vessel 120 travels though the water, the firing
position of source 110 will change. The different positions
of source 110 can be then be used to construct data in the
common receiver domain as is well known in the art.
15   While preferred embodiments of the invention have
been described, the descriptions and figures are merely
illustrative and are not intended to limit the present
invention.

CLAIMS

What is claimed is:

5   1.   A method of reducing the effects in seismic
data of downward propagating reflected and scattered
acoustic energy travelling in a fluid medium comprising the
steps of:
                    receiving pressure data representing at least
10   the pressure in the fluid medium at a first location
and a second location, the first location being in
close proximity to the second location;
                    receiving vertical particle motion data
representing at least the vertical particle motion of
15   acoustic energy propagating in the fluid medium at a
third location and a fourth location, the third
location being in close proximity to the fourth
location, and the first, second, third and fourth
locations being within a spatial area;
20   calculating a plurality of spatial filter
coefficients based in part on the velocity of sound in
the fluid medium, the density of the fluid medium and a
plurality of acquisition parameters, thereby creating a
spatial filter which is designed so as to be effective
25   at separating up and down propagating acoustic energy
over a range of non-vertical incidence angles in the
fluid medium;
                    applying the spatial filter to the vertical
particle motion data to generate filtered particle
30   motion data;

combining the filtered particle motion data
with the pressure data to generate separated pressure
data, the separated pressure data having up and down
propagating components separated; and

5   analysing at least part of the up or down
propagating component of the separated pressure data.

2.   The method of claim 1 wherein the acquisition
parameters include the temporal sampling interval, the
10   spatial sampling interval, and the number of independent
locations at which the pressure and vertical particle motion
data are measured.

3.   The method of claim 1 wherein the vertical
15   particle motion data is measured using one or more multi-
component streamers.

4.   The method of claim 1 wherein the vertical
particle motion of the acoustic energy represented in said
20   vertical particle motion data is the particle velocity of
the acoustic energy.

5.   The method of claim 1 wherein the vertical
particle motion of the acoustic energy represented in said
25   vertical particle motion data is the vertical pressure
gradient of the acoustic energy.

6.   The method of claim 5 wherein the pressure
gradient is measured using at least two parallel streamer
30   cables in close proximity and vertically offset from one
another.

7.   The method of claim 1 wherein the vertical
particle motion of the acoustic energy represented in said
vertical particle motion data is the vertical displacement
5 of the acoustic energy.

8.   The method of claim 1 wherein the vertical
particle motion of the acoustic energy represented in said
vertical particle motion data is the vertical acceleration
10 of the acoustic energy.

9.   The method of claim 1 wherein the distance
between the first location and the second location and the
distance between the third location and the fourth location
15 is less than the Nyquist spatial sampling criterion.

10.   The method of claim 9 wherein the spatial
area is substantially a portion of a line, and the range of
non-vertical incidence angles includes substantially all
20 non-horizontal incidence angles within a vertical plane that
passes through the portion of line.

11.   The method of claim 9 wherein the spatial
area is a portion of a substantially planar region, and the
25 range of non-vertical incidence angles include substantially
all non-horizontal incidence angles.

12.   A method of reducing the effects in seismic
30 data of downward propagating reflected and scattered

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acoustic energy travelling in a fluid medium comprising the
steps of:

          receiving pressure data representing at least
the pressure in the fluid medium at a first location
5   and a second location, the first location being in
close proximity to the second location;

          receiving vertical particle motion data
representing at least the vertical particle motion of
acoustic energy propagating in the fluid medium at a
10   third location and a fourth location, the third
location being in close proximity to the fourth
location, and the first, second, third and fourth
locations being within a spatial area;

          calculating a plurality of spatial filter
15   coefficients based in part on the velocity of sound in
the fluid medium and the density of the fluid medium,
thereby creating a spatial filter which is designed so
as to be effective at separating up and down
propagating acoustic energy over a range of non-
20   horizontal incidence angles in the fluid medium;

          applying the spatial filter to the pressure
data to generate filtered pressure data;

          combining the filtered pressure data with the
vertical particle motion data to generate separated
25   pressure data, the separated pressure data having up
and down propagating components separated; and

          analysing at least part of the up or down
propagating component of the separated pressure data.

30

13. The method of claim 12 wherein the distance
between the first location and the second location and the
distance between the third location and the fourth location
is less than the Nyquist spatial sampling criterion.

5

14. The method of claim 12 wherein the vertical
particle motion data is measured using one or more multi-
component streamers.

10   15. The method of claim 12 wherein the vertical
particle motion of the acoustic energy represented in said
vertical particle motion data is the particle velocity of
the acoustic energy.

15   16. The method of claim 12 wherein the vertical
particle motion of the acoustic energy represented in said
vertical particle motion data is the vertical pressure
gradient of the acoustic energy.

20   17. The method of claim 16 wherein the pressure
gradient is measured using at least two parallel streamer
cables in close proximity and vertically offset from one
another.

25   18. A method of reducing the effects in seismic
data of downward propagating reflected and scattered
acoustic energy travelling in a fluid medium comprising the
steps of:
                  receiving pressure data representing at least
30   variations in pressure in the fluid medium at a first
            location, the variations caused in part by a first

source event and a second source event, the first
source event and the second source event being within a
spatial area;

5   receiving vertical particle motion data
representing at least the vertical particle motion of
acoustic energy propagating in the fluid medium at a
second location, the acoustic energy being caused in
part by the first source event and the second source
event;

10   calculating a plurality of spatial filter
coefficients based in part on the velocity of sound in
the fluid medium and the density of the fluid medium,
thereby creating a spatial filter which is designed so
as to be effective at separating up and down

15   propagating acoustic energy from the first source event
and second source event over a range of non-horizontal
incidence angles in the fluid medium;

applying the spatial filter to the vertical
particle motion data to generate filtered particle

20   motion data;

combining the filtered particle motion data
with the pressure data to generate separated pressure
data, the separated pressure data having up and down
propagating components separated; and

25   analysing at least part of the up or down
propagating component of the separated pressure data.

          19.   The method of claim 18 wherein the first
source event and the second source event are generated by

30   firing a seismic source at different locations at different
times, and the distance between the location of the first

                              26

source event and the location of the second source event is
less than the Nyquist spatial sampling criterion.

20.   The method of claim 18 wherein the vertical
particle motion data is measured using one or more multi-
component streamers.

21.   The method of claim 18 wherein the vertical
particle motion of the acoustic energy represented in said
vertical particle motion data is the particle velocity of
the acoustic energy.

22.   The method of claim 18 wherein the vertical
particle motion of the acoustic energy represented in said
vertical particle motion data is the vertical pressure
gradient of the acoustic energy.

23.   The method of claim 22 wherein the pressure
gradient is measured using at least two parallel streamer
cables in close proximity and vertically offset from one
another.

24.   A computer-readable medium which can be used
for directing an apparatus to reduce the effects in seismic
data of downward propagating reflected and scattered
acoustic energy travelling in a fluid medium comprising:
           means for retrieving pressure data
       representing at least the pressure in the fluid medium
       at a first location and a second location, the first
       location being in close proximity to the second
       location;

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means for retrieving vertical particle motion
data representing at least the vertical particle motion
of acoustic energy propagating in the fluid medium at a
third location and a fourth location, the third
5   location being in close proximity to the fourth
location, and the first, second, third and fourth
locations being within a spatial area;
means for calculating a plurality of spatial
filter coefficients based in part on the velocity of
10   sound in the fluid medium, the density of the fluid
medium and a plurality of acquisition parameters,
thereby creating a spatial filter which is designed so
as to be effective at separating up and down
propagating acoustic energy over a range of non-
15   vertical incidence angles in the fluid medium;
means for applying the spatial filter to the
vertical particle motion data to generate filtered
particle motion data;
means for combining the filtered particle
20   motion data with the pressure data to generate
separated pressure data, the separated pressure data
having up and down propagating components separated;
and
means for analysing at least part of the up
25   or down propagating component of the separated pressure
data.

25.   The computer-readable medium of claim 24
wherein the distance between the first location and the
30   second location and the distance between the third location

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and the fourth location is less than the Nyquist spatial
sampling criterion.

26.   The computer-readable medium of claim 24
5   wherein the vertical particle motion data is measured using
one or more multi-component streamers.

27.   The computer-readable medium of claim 24
wherein the vertical particle motion of the acoustic energy
10   represented in said vertical particle motion data is the
particle velocity of the acoustic energy.

28.   The computer-readable medium of claim 24
wherein the vertical particle motion of the acoustic energy
15   represented in said vertical particle motion data is the
vertical pressure gradient of the acoustic energy.

29.   The computer-readable medium of claim 28
wherein the pressure gradient is measured using at least two
20   parallel streamer cables in close proximity and vertically
offset from one another.

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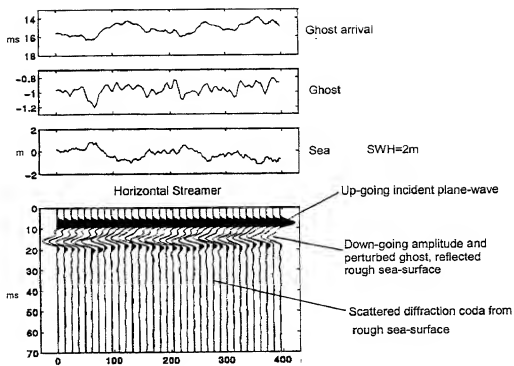

Figure 1

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Figure 2 (prior art)

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Full Filter (solid), 1st Taylor (plus)
Fraction expansion (dash-dot)

Figure 3 (prior art)

4/13

Figure 4

5/13

Figure 5

6/13

Fig. 6a

Seismic vessel
Seismic source
122d   112   Sea Surface
120   110   122c   Down-going
receiver ghost   Streamer depth
e.g., 60m
Seismic streamer
118   Seismic energy
114
122a   Up-going reflection
Sea floor
Transmitted signal
122b

Fig. 6b

Sea Surface
112   P v_x v_y v_z 126b   126c
126a   128c
128a   e.g., < 12m   128b   124

Fig. 6c

Sea Surface
112   P   dP/dz   130   136c
132a   134c
134a   e.g., < 12m   132b   134b

Fig. 6d

Sea Surface
112   142a   P   142b   140a   142c
Streamer separation
e.g., <2m   140b
142d   e.g., < 12m   142e   142f

Fig. 6e   Fig. 6f

140a
140b   140c
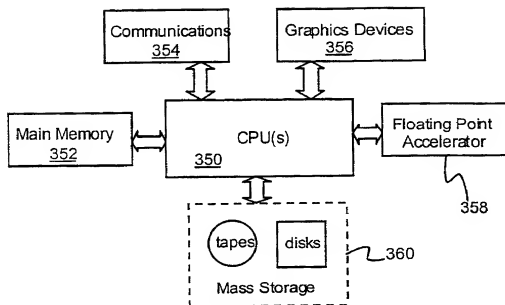
Figures 6a-f

Figure 7
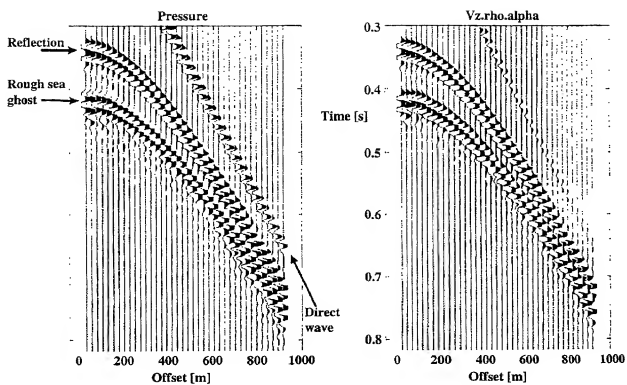
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Figure 8

Figure 9

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Figure 10

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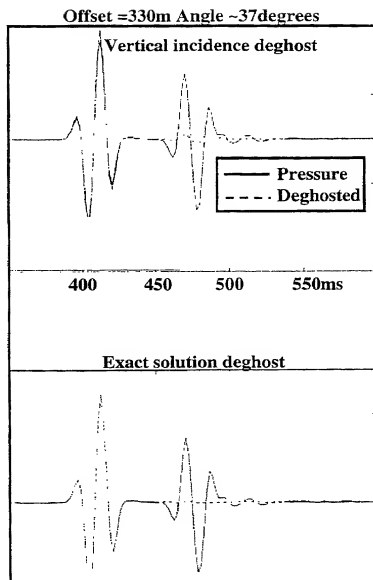

Figure 11

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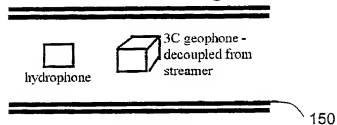Figure 12

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4C recording

150

Figure 12a
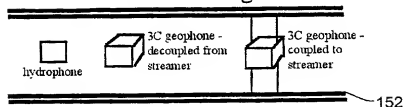
7C recording

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Figure 12b

DECLARATION FOR PATENT APPLICATION AND POWER OF ATTORNEY

As a below named inventor, I/We hereby declare that:

My/Our residence, post office address(s) and citizenship(s) are as stated below next to my/our name(s), and

I/We believe I/We am/are the original, first and sole inventor of the subject matter which is claimed (if only one name is listed below) or an original and first inventor of at least some of the subject matter which is claimed (if plural names are listed below) and for which a patent is sought on the invention entitled

<div align="center">

METHOD AND SYSTEM FOR REDUCING EFFECTS OF SEA SURFACE GHOST
CONTAMINATION IN SEISMIC DATA

</div>

the specification of which

☐   is attached hereto.

☒   was filed on 21 March 2000

      as PCT International Application No. PCT/GB00/01074

      and was amended on _____ (if applicable).

I/We hereby state that I/we have reviewed and understand the contents of the above identified specification, including the claims, as amended by any amendment referred to above.

I/We acknowledge the duty to disclose information which is material to the examination of this application in accordance with Title 37, Code of Federal Regulations, Section 1.56(a).

<div align="center">

Prior Foreign Application(s)

</div>

I/We hereby claim foreign priority benefits under Title 35, United States Code, Section 119 of any foreign application(s) for patent or inventor's certificate listed below and have also identified below any foreign application(s) for patent or inventor's certificate having a filing date before that of the application on which priority is claimed:

Country	Application No.	Filed (d/m/y)	Issued (d/m/y)	Priority Claimed
Great Britain	9906456.0	(22/03/99) 22 March 1999		Y ☒ N ☐

<div align="center">

Prior United States Applications

</div>

I/We hereby claim the benefit under Title 35, United States Code, Section 120 of any United States application(s) listed below and, insofar as the subject matter of each of the claims of this application is not disclosed in the prior United States application in the manner provided by the first paragraph of Title 35, United States Code, Section 112, I/We acknowledge the duty to disclose material information as defined in Title 37, Code of Federal Regulations, Section 1.56(a) which occurred between the filing date of the prior application and the national or PCT international filing date of this application:

Application Serial No.	Filing Date (d/m/y)	Status (Patented, Pending, Abandoned)

And, I/We hereby appoint, both jointly and severally, as my attorney(s) and/or agent(s) with full power of substitution and revocation, to prosecute this application and to transact all business in the Patent and Trademark Office connected herewith the following attorney(s) and agent(s), their registration numbers being listed after their names.

John J. Ryberg, 31,134; William B. Batzer, 37,088; Erica W. Kuo, 42,775; and William L. Wang, 39,871

I/We hereby request that all correspondence be directed to:
Intellectual Property Law Department,
Schlumberger-Doll Research,
Old Quarry Rd., Ridgefield, CT 06877,
and that all telephone calls be directed to Patent Department at (203) 431-5507.

I hereby declare (if sole inventor) or each of us hereby declares (if joint inventors) that all statements made herein of my own knowledge are true and that all statements made on information and belief are believed to be true; and further that these statements were made with the knowledge that willful false statements and the like so made are punishable by fine or imprisonment, or both, under Section 1001 of Title 18 of the United States Code and that such willful false statements may jeopardize the validity of the application or any patent issuing thereon.

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